Executive Summary

October 13, 2000

Market Surveillance Administrator
Report on Power Pool of Alberta Prices – Summer 2000
Executive Summary

Since the Power Pool of Alberta (PPoA) began operation in 1996, some of the highest average spot market prices ever recorded occurred during the Summer of 2000. The Market Surveillance Administrator (MSA) routinely monitors the electricity market, however, the expression of concerns to the Energy and Utilities Board and the Department of Resource Development, coupled with the high market prices of this summer, provided additional impetus for the MSA to examine the electricity market which prompted this report.

This review also facilitates an assessment of how market monitoring processes and procedures can in themselves, be enhanced. The MSA is committing resources toward an improve program of monitoring approaches and tools in the PPoA, as well as towards development of standards for market participant behaviour and enforcement approaches.

In examining price volatility during the summer months of 2000, the review process considered price drivers such as the supply/demand balance situation, electricity prices in other markets, natural gas prices, market structure factors and market participant behaviour.

The MSA will direct this more detailed review to be carried out over the next month and will provide results as part of its ongoing reporting. Other areas, which were evaluated and are considered priorities, are outlined in the recommendation section below.

Report Objectives

This examination is not intended as a comprehensive evaluation of the high Pool spot market price for this summer but, rather, the objective of this report is to:

(a) Identify price drivers and factors that may have contributed to high Pool prices this summer.
(b) Identify areas of concern that require more detailed review or investigation.
(c) Provide the MSA's plan of action to address areas of concern.
(d) Recommend initiatives to be considered by the Power Pool of Alberta and other agencies, as well as stakeholders.

This report does not offer hard and fast conclusions or directions. Instead a series of recommendations emanated from this preliminary review. These are listed below as action items or priority areas:

Recommendations

A. The MSA will undertake a review of power generating unit outages, derates and maintenance practices of regulated units during spring and summer of 2000. The MSA has taken early steps to retain a consultant to carry out this review. Study results will be shared between the PPoA, Alberta Energy and Utilities Board, and the Transmission Administrator.

B. The MSA will design and implement a process around ongoing collection of information and reports from generators on planned maintenance and forced outages. This data will be collected to develop criteria to ensure compliance with the of availability provisions under the Power Purchase Arrangements (PPA).

C. The MSA recommends the PPoA, in the very near term, develop and implement appropriate rule changes to deal with the impact of interconnection concerns as discussed in the report.

D. The MSA recommends the PPoA should review and evaluate the PPoA market design and various rules relating to the market to ensure the appropriate balance between flexibility offered to suppliers and the need for meaningful price transparency.

   The MSA suggests that the PPoA undertake a review of the price cap level, price cap setting methodologies and approaches that would be appropriate (including offer or revenue caps or adjustable caps).

E. The MSA is committing additional resources towards an improved program of monitoring approaches and tools in the PPoA, as well towards development of standards for market participant behaviour and enforcement approaches.

F. The MSA encourages stakeholders, especially on the demand, or load side, to take an active role to set the direction for price responsiveness, types of offerings and valuation methods for interruptability. The MSA urges industry organizations and stakeholders as well as individual, joint venture or aggregated customers to assist in bringing the proper price signals to the market.

G. The MSA recommends Alberta Department of Resource consider opening up direct sales eligibility requirements. Consideration of structural changes, which may be appropriate, such as a capacity market, and the relationship of that within the energy and ancillary market framework, is encouraged.

H. The MSA recommends that the Transmission Administrator (TA) explore additional opportunities or arrangements for providing operating reserves that bring in new sources of supply (arrangements with other jurisdictions, further offerings for curtailable load) which may be achieved through the ancillary services market or otherwise.

I. Alberta's place in a Regional Transmission Organization is a pivotal strategic issue. Groundwork should start now to facilitate the appropriate level of facilities and siting of new interconnections which may be needed to truly open up the Alberta market in order to meet demand and encourage generation development within Alberta.

Price Drivers

The MSA determined a combination of factors have contributed to high market prices over the summer months this year. Under the classification of ***market fundamentals***, these factors include:

- Fuel prices
- Electricity prices (opportunity costs) in other regional markets
- Supply/demand balance
- Weather and precipitation
- Hydro generation and its characteristics
- Operating reserves carried on the system
- Maintenance and forced outages of regulated generators
- Supply growth relative to demand growth
- Technical limitations on the interprovincial interconnections

The MSA concluded four key ***market structure*** factors have also had an effect on market prices. These are workable competition, demand-side participation, the lack of a forwards market and the regulatory structure relating to open-access to British Columbia.

Finally, the MSA discussed various ***behavioural factors***, which are seen to contribute to the market prices experienced over the summer months this year, as well as the exercise of market power. The MSA stated that the direction and viewpoints of Alberta Department of Resource Development on the general issue of market power exercise, and the desired approaches, need to be articulated.

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MARKET SURVEILLANCE ADMINISTRATOR REPORT ON POWER POOL OF ALBERTA PRICES – SUMMER 2000

I INTRODUCTION

The following comprises the comments of the Market Surveillance Administrator ("MSA") on the high electricity prices experienced in the Power Pool of Alberta ("PPoA") market during the summer of 2000. The objective of this report is also to provide the MSA's plan of action on a path forward to deal with some of the concerns that have been identified thus far to require more detailed review or investigation. In addition, broader recommendations and comments on initiatives to date are included for the consideration of the Power Pool Council, as well as stakeholders.

This is not intended to be a comprehensive evaluation or presentation of price information for the summer of 2000. Rather, it is intended to frame the influences on the PPoA prices during this period as between problems caused by fundamentals, versus problems which are, or appear to be, caused or facilitated by Participant decisions or by design or structural problems in the market. In the MSA's view, it is essential to make this distinction in order to inform the debate on price levels and increases in volatility. This is the first step toward the PPoA and other stakeholders being able to direct efforts where they can lead to meaningful results. It should also help to develop an understanding or at least advance the debate to the next stage – that being, what influences on prices cannot or should not be dealt with by market design changes or rules enforcement?

Given the interaction of the factors driving price and the need to further analyze and/or develop data in some areas, this commentary is not conclusive on causation. It will, however, flag areas of concern and next steps. Note that the discussion in this paper is dealing with wholesale electricity prices in the PPoA market, except where the context requires otherwise.

II DATA SUMMARY

The year to date PPoA average price (as of end of September) is $102.97/MWh. The average Pool price as of Aug. 31 was $93.95/MWh.

The average PPoA price in September was $176.28/MWh.

The following shows a comparison of average peak and average off-peak prices for 1999 and 2000, by month, and year over year changes for each month.

AVERAGE PEAK PPoA PRICES ($/MWh)				
	1999	2000	% Change	$ Change
Feb	30.959	55.12	78.08	24.17
Mar	33.84	105.87	212.84	72.03
Apr	39.04	120.45	208.57	81.42
May	69.53	67.06	-3.55	-2.47
Jun	75.04	138.11	84.05	63.07
Jul	40.64	181.23	345.95	140.59
Aug	99.71	297.97	198.84	198.26
MEAN	55.54	137.97	160.68	82.44

AVERAGE OFF PEAK PPoA PRICES ($/MWh)				
	1999	2000	% Change	$ Change
Feb	24.69	36.20	46.61	11.51
Mar	23.33	37.49	60.72	14.16
Apr	20.93	60.11	187.12	39.17
May	29.78	32.13	7.89	2.35
Jun	26.68	62.78	135.27	36.10
Jul	18.07	57.70	219.40	39.64
Aug	24.30	69.34	185.34	45.04
MEAN	23.97	50.82	120.34	26.85

III PRICE DRIVERS

In the view of the MSA the factors influencing prices can be aggregated into three main categories:

A. Fundamentals (including generation input costs, opportunity costs and the various factors affecting supply-demand balances, both intra- and extra-Alberta).

B. Structural concerns with the market (including issues around horizontal concentration in supply, demand participation, level of open access in adjacent jurisdiction, and lack of forwards markets).

C. Behavioural (actions and strategies of PPoA participants, and regulatory incentives).

A. Fundamentals

A great deal of information is already out in the public domain on gas prices and on electricity prices in other jurisdictions. As such, and since (based on our analysis) the fundamentals do not of themselves explain the price levels experienced, we do not propose to outline in any great detail further data or analysis such as the level of correlation between the

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PPoA and other markets. A few comments are pertinent however to reflect the basic impacts of these factors.

1. Fuel prices

The increase in natural gas prices over last year is significant. This is a regional, not just an intra-Alberta phenomenon. Gas-fired generators in the western interconnection are facing fuel costs approximately double what they experienced last year. These cost increases are legitimately passed through via higher offer prices for the electricity being generated from gas units in Alberta. In addition, higher gas prices mean higher opportunity costs for non gas-fired generators given the increase in electricity prices in other markets.

Clearly, with approximately 70% of generation within Alberta being coal-fueled base load plants, the increase in electricity prices is not adequately explained by gas cost increases. The impacts are a function of the fact, among other things, that gas facilities serve peak loads.

The story on other fuel costs—coal and water—is quite different. There have been no material increases. Going forward, the coal facilities are under the Power Purchase Arrangements ("PPA's") with a virtually flat cost profile, and water rentals are already nominal ($0.85/MWh) on their way to even more nominal ($0.10/MWh). Moreover, with hydro, as discussed below, the input costs have very little to do with bidding strategies; these facilities arguably exist for water conservation and fisheries management with electricity as a byproduct.

2. Electricity prices in other markets (opportunity costs)

Alberta is not alone in terms of recent price escalation in electricity markets. Prices for power are higher this year than last, in almost all de-regulated electricity markets in North America. An illustration of this is shown in the graph below (which shows month over month peak price increases for the period February to July of 2000). The cost of imported energy being offered into the PPoA is higher as a result. There has also been a dramatic increase in off-peak prices in various markets in the western interconnection (less so in MAPP) as shown in Table 1 below.

Across the U.S., recent data suggests that wholesale power prices have more than doubled at 14 of 17 key hubs over the past three years (see Table 2 below which shows percentage change in wholesale electricity prices at various transmission-interconnection points between 1997 and May 2000. All data was provided by the Federal Energy Regulatory Commission ("FERC").

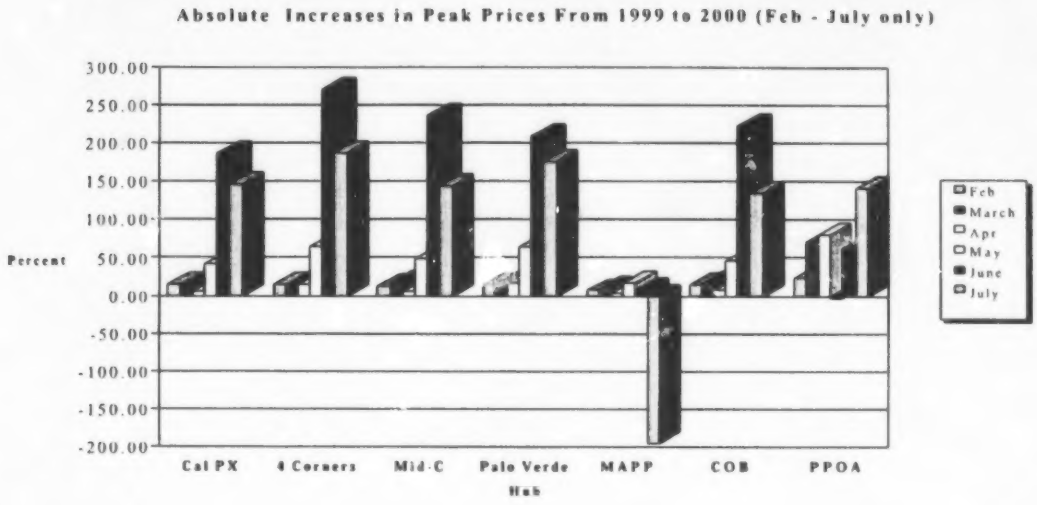


TABLE 1

% Change in Off-Peak Prices 2000 vs 1999; WSCC markets and MAPP

	Cal PX	COB	4 Corners	Mid-C	Palo Verde	MAPP
Feb	86.98	87.75	64.64	80.66	73.08	19.33
March	62.71	101.49	86.06	115.51	64.70	14.50
Apr	-4.76	16.71	25.97	4.67	2.12	16.80
May	81.58	98.69	78.78	105.32	59.47	15.41
June	312.23	402.79	239.41	643.19	235.46	20.74
July	189.29	266.40	135.36	317.96	157.30	14.85
August	326.96	367.38	N/A	438.27	215.65	28.62

TABLE 2

Transmission-Interconnection Point	% Change in Electricity Prices 1997-2000
Texas	+ 293%
Louisiana-Mississippi Arkansas	+ 216%
Tennessee Valley Authority	+ 165%
California-Oregon Border	+ 162%
New York-West	+ 138%
Chicago	+ 130%
New England	+ 117%
New York-East	+ 101%
Upper Midwest	+ 99%
Florida	- 89%
Mid-Atlantic Region	+ 80%

The level of prices in other markets is a key factor influencing the level of import volumes which are able to be made available to Alberta, as well as the level of export and PPoA prices because of increased demand due to higher export volumes from Alberta. Alternative markets create opportunity costs for (importer) suppliers, the true costs of which are a legitimate pass through to offer prices. The impact of higher export volumes has been felt strongly in the impacts on off-peak prices in the PPoA. High off-peak prices in other markets have led to an increase in the demand for Alberta power for export –thus putting upward pressure on off-peak prices in the PPoA. As shown in the data tables in Section 2 above, average off-peak prices have more than doubled in the period February to August of 2000.

It also should be noted that the price levels in other jurisdictions are impacted by any number of fundamental factors (such as input costs, scarcity, emissions credits, opportunity costs), as well as market problems in those jurisdictions (such as exercise of market power, or supply-demand tightness putting upward pressure on prices).

3. Supply-Demand Balance

A number of sub-factors impact on the supply-demand balance, overall and at particular times. Some of these have impacted intra-Alberta supply and demand directly, while others have been more influential on either or both of

(i) opportunity cost, with applicability both to import costs (and resultant prices) and impact of exports on PPoA prices,

(ii) import supply availability and export levels.

At its simplest, the greater the demand relative to the level of available supply, the higher the cost of generating units required to be dispatched to meet demand and operating reserves requirements. Units farther up the merit order are required in times of high demand. Further, periods of tightness can be caused by unavailability of units (rather than, or in addition to, increase in loads) and some of the unavailable units may be the lower cost units. As such, blocks in the merit order will be disproportionately supplied by higher cost units than typically.

(a) *Weather/Precipitation*: Impacts from weather and related factors have been felt in at least three senses. Firstly, higher temperatures experienced in the Pacific Northwest and California have created high loads, with attendant impacts on import/export levels, and prices in those markets. (Recently published statistics indicate that the summer of 2000 has been the second hottest on record for the United States southwest). Secondly, water levels in the Pacific Northwest this year have been lower than in previous years due to levels of precipitation, impacting on both hydro supply availability and pricing of hydro. Hydro units are unique in that pricing of energy is impacted and driven by water conservation/management and storage concerns. Thirdly, weather impacts the efficiencies of thermal generators. Discussion of hydro related impacts follows in paragraph (b) and thermal impacts in paragraph (d) (Maintenance and Forced Outages).

(b) *Hydro*: The tightness of supply due to other factors has resulted in the intra Alberta hydro units (TransAlta Utilities) setting prices over $100/MWh for a larger percentage of the time this summer than previously. All other things being equal, given the limitations on alternate supply, the need to dispatch up to the higher price blocks sourced from hydro assets has been greater. A thorough analysis of the bidding patterns of hydro units has not been undertaken and accordingly at this point it cannot be concluded whether and to what extent these units have been offered in differently than previously, and the justification therefor.

It is clear, though, that there is a marked difference between the level of price setting by hydro this year over last. For example, in the January to July period in 1999 hydro resources never set price at levels above $100, but during the corresponding period in 2000, hydro was pivotal a significant portion of the time both above $100 and above $500. It is also noted that the degree of price setting over $500 is dominated by the hydro units, with importers' high offers typically just under $500.

To put this in perspective, however, it should be noted that the time during which the PPoA price was at or over $500 was significantly less than the time during which it was between $100 and $499. As such, the high price bands overall (i.e., $100 to $500, and $498 and above) show a significant role for importers in price setting—dominated by BC Power Exchange ("Powerex"). For further discussion of imports see Section B. 4 below. For April as an example, hydro price setting above $498 amounted to approximately 17% of the time at those levels, with Powerex accounting for approximately 76% of those hours. It is also noteworthy that the $498 plus hours accounted for some 44% of the total time Pool Price was $100 or greater.

For graphical depiction of some of this information see Attachment A.

(c) *Operating Reserves:* The supply of energy is impacted by the need for the system to carry operating reserves, a buffer over and above the level of demand. The amount of operating reserves that must be carried at any time is determined under the Transmission Administrator's ("TA") policies. In accordance with this policy at the present time, typically the amount of operating reserves carried on the system varies between 465 MW and 600 MW, depending the system load.

The suppliers of operating reserves are generally generation sources, the same suppliers that play in the energy market. Consequently, when they are delivering operating reserves, their supply is not available to serve load. Once again, this can take out some relatively lower priced resources and require dispatching further up the merit order.

(d) *Maintenance and Forced Outages of Regulated Generators*. There has been a great deal of suggestion and innuendo that causation for high prices during the spring and summer of 2000 has been by design, in the maintenance scheduling practices of the regulated generators, or in the duration and frequency of unplanned derates and the time for restoration to availability. These concerns and assertions have been put into public view and articulated before the regulator (Alberta Energy and Utilities Board [AEUB]) as well as to the Alberta Department of Resource Development ("ADRD"). In particular, the Industrial Power Consumers and Cogenerators Association of Alberta (IPCCAA) and the City of Lethbridge have voiced concerns. The MSA has had some informal discussions with a number of parties, but has not received, as yet, an official complaint in respect to this matter.

The implication is that there is the ability and a potential benefit to the regulated generators in "managing" toward a shortness in supply, either with coincident maintenance, more frequent outages and derates, or by extension of outages and derates. In theory, benefits from higher prices which accompany shortness in supply could be taken to the extent the utilities are net sellers (long) and through ownership of Independent Power Producer ("IPP") positions which have grown since the legislated hedges have been put in place.

This describes the nature of the issues which have been raised, and the theories or assumptions held by those speaking to them.

With the analysis the MSA has been able to do to this point, no conclusion can be drawn as to the supportability of any concerns.

An important point is that assessments of availability of generation to the system assume no outages and derates during the annual turnaround period, and as such show the maximum potential availability. Forced outages and derates do, of course, occur. Some of the information gathered to date by the MSA indicates both TransAlta and EPCOR have experienced higher-than-forecast forced outages and derates this summer season. This, apart from any influence of maintenance scheduling and performance, would put further strain on the system and available supply. The following more notable

observations may provide some context to the generator picture for the spring and summer months:

- Three outages at Genesee;
- Warm weather during the summer negatively affects the efficiency of thermal plants, further exacerbating supply tightness. Given the magnitude and duration of hot and dry periods this summer, there were extensive derates at Wabamun and Sundance;
- For one of the utilities, approximately 40% greater number of outages on units than expected based on typical or historical performance for its units;
- Extensive outage on Wabamun #4 which still persists;
- Keephills units were taken off line earlier this year for four-week outages (one after the other) to repair critical turbine problems identified in late 1999. TransAlta applied for, and was granted, Temporary Suspension Regulation (TSR) relief of the related entitlement obligations under the EUA. These outages took place in March and April and had the impact of pushing other planned turnarounds deeper into the summer months;
- In terms of other physical factors, tie line trips due to electrical storm activity were up this year over last year (3 trips compared to one).

It should also be remembered that the window for maintenance in terms of major turnarounds is the spring, summer and fall months, and due to that inflexibility, it is always the case that there will be simultaneous unavailability of major units. Limitations on labour and resources do, however, mitigate against coincident scheduling to some degree.

Having said all that, however, the MSA is concerned with the lack of specific information presently available to him. Other perspectives have been given to the MSA that the spring/summer period was not unusual in the level or scheduling of maintenance, and in fact some maintenance was deferred until 2001. At present, there is no way to confirm or challenge that position or the contrary perception that has been raised by stakeholders, absent a detailed investigation of primary source data from the utilities themselves. More clarity would benefit all involved, and as such further analysis and review is indicated.

Another concern from the MSA's perspective is access to information about facility availability on an ongoing basis. The need for information, in particular for review of compliance with the Power Purchase Arrangements and monitoring performance for that purpose, will increase going forward. At the same time, for commercial reasons, the buyers of the PPA's may well be reluctant to have the same level of availability of information to the PPoA, and in particular to PPoA Participants, as is presently the case. An independent sourcing of information for the MSA's purposes is required given the possibility of even further restrictions on the already limited amount of information in the possession of the PPoA. The role of the AEUB in tracking this kind of information should also be reviewed, and possibly increased along the lines of the reporting required in the oil and gas sector.

The MSA's comments in this regard should not be viewed as critical of the PPoA's sourcing of information as to causation of outages or maintenance scheduling. The focus to date for the PPoA has been dealing with and deferring maintenance as necessary for reliability purposes. Neither is this commentary intended to be critical of the PPoA's or the TA's role in planning and management of annual turnarounds.

Further, the extent to which strategic behaviour involved in maintenance planning could be effectively utilized by the utilities, or to which it should be considered a problem which has a remedy, is limited. The mitigating effects of the legislated hedges put a rein on any such strategy. Beyond that, the structure of the market does not require producers to generate—there is presently not an installed capacity or other form of committed capacity market in Alberta. The validity of outages and maintenance practices is and should be, however, of concern to the Transmission Administrator in the context of reviewing compliance under its reserves contracts, and will need to be addressed in their ancillary services market design.

More information collection and analysis is needed to characterize technical issues, if any, and to capture the magnitude of any impacts. This may or may not lead to follow-on consideration of new market structure or design approaches to ensure generation "makes it to market." All of this has to be approached carefully with a view to the valid expectations of market players, such as the PPA buyers and owners.

(e) *Supply Growth Relative to Growth of Demand*: The "supply cushion" within Alberta has been eroding over time. Uncertainty, associated with the original Electric Utilities Act ("EUA"), as to the ultimate deregulated industry structure and the staged-in approach to deregulation in Alberta caused to some degree reluctance on the part of suppliers to invest in new supply. These uncertainties were addressed by amendments to the EUA and new supply is gradually being brought in, but the supply "headroom" that was formerly the case has been absorbed. The buffer was the result of the regulated approach to building generation—allowing for increments well in advance of demand growth-- as well as the large size of thermal plants that were brought on.

There is also the appearance of a larger planned program of additions than has been the case in reality. Firstly, the gains come from new IPP capacity which are "behind the fence" and serve local load, not incrementing generation on the system to the degree the nominal capacity would suggest. The numbers quoted in regard to new supply are often gross numbers, which overstate the net capacity brought to the system.

Also, certain new IPP facilities previously on line or anticipated to be on line before the summer season have experienced unexpected commissioning or operating problems. This has resulted in about 600 MW of supply capability not being available during the critical maintenance period this summer.

The rest of the story is in the number of forced outages and derates this year, as well as the demand side. The stresses on the supply have been more acute since demand has been growing steadily through a robust Alberta economy. Peak loads have exceeded

7,000 MW on numerous occasions, putting further pressure on the market and reserve margins. Growth in average demand year over year for January to August of 2000 versus the corresponding period in 1999 has averaged just over 5%. Attachment B shows month to month and year over year comparisons of demand (average, maximum and minimum) as well as some PPoA price measures for those periods.

(f) *Technical Limitations on the Interconnections*: Alberta is served by interconnections to the west and to the east, with combined capability of 950 MW. The ability to bring in external supply to relieve from internal constraints is technically limited. This also exposes Alberta to concerns with structural/regulatory issues in other provinces –i.e., interconnection to provinces which are not themselves deregulated, with the attendant issues around access to transmission space (see further discussion below).

Although not strictly a function of interconnection size (importer alternate opportunities, and structural/regulatory factors being influential as well) it is noted that imports are significantly down January to July of 2000 over the corresponding period last year. Despite increases on the Saskatchewan side (by MWh volume), where import supply generally increased this year, the overall contribution of imports is down due to the decrease experienced in imports from the west.

Added to the pressure on intra-Alberta supply there has been an increase in exports to BC, particularly in the May to August time frame. Without further analysis it is difficult to quantify the impact on Alberta prices due to this. Again to the extent that the explanation is in the higher prices available in outside markets, this is consistent with fundamentals. See further discussion, however, under Part B (Structural Factors).

See Attachment C for export and import graphs.

B. Structural Factors

Industry or market structure factors have been more or less influential on summer 2000 prices as follows:

1. Workable Competition: At present, the challenges to workable competition that are provided by the utilities' market share concentration in regulated generation are largely handled by the legislated hedges. As noted above, however, there is some softness in the legislated hedges' ability to provide "market power mitigation" to the extent that the holders of the regulated units are also in IPP's or are otherwise net sellers. Going forward, the position limits under the PPA's arguably should provide the same type of market discipline on the buyers of the PPA's.

   This comment is subject to the caution that the ability to exercise market power is not determined solely at the industry market share level, given overall supply tightness or even situational/temporary limitations in supply. See further discussion under Part C.

2. Demand-Side Participation: The ability of demand-side participation to moderate prices in an equilibrium market such as the PPoA is fundamental and well understood. The concerns about the lack of demand participation should not be understated. At present, given the stage of deregulation and the incremental approach taken, significant demand-side response is essentially non-existent. With a virtually inelastic demand curve, market discipline can only come from the supply side and/or through price caps. Otherwise, demand simply is a price taker – the price is the price level on the supply curve corresponding to the quantity level set by system load. With a supply curve that is a step function this can result in material price changes as load increases (particularly given very large and high steps at the top of the supply curve, which can occur in times of tight supply). Given the needs of load, and no significant price sensitive loads, suppliers can offer in at least some quantities at high prices with not a great deal of risk of not being dispatched—see further discussion under Section C.

3. Lack of Forwards Markets: Properly designed and functioning forwards or futures markets should introduce liquidity to the Alberta electricity market overall, create a reference price for bilateral deals, and help to take some of the "noise" out of the PPoA spot market that results from a lack of price certainty (ex-post price setting), and offer strategies ostensibly used to offset that. Currently those benefits are not available. The best information available to the PPoA is that both potential forwards market operators are on track for trading within Q4 2000, with transactions to be effective as early as January 2001.

4. Regulatory structure around open-access from British Columbia: Lack of liquidity in the PPoA spot market and supply tightness is reinforced by the regulatory structure for transmission access from or into British Columbia.

   Various concerns have been noted to the MSA from Participants, which are inherent to the form of tariff used by BC Hydro (modeled on the FERC Open-Access Tariff) and/or the implementation of that tariff. It is critical to understanding the recourse available to Alberta that none of the Alberta regulators, including the MSA, have any jurisdiction over these matters.

   Given the jurisdictional limitation on the MSA, it is beyond the scope of this commentary to provide a great deal of detail around issues with the BC Hydro WTS tariff. However, some key concerns expressed to the MSA include the following:

   (a) Existing hold on long-term firm BC/Alberta interconnection capacity by Powerex. Powerex is a wholly owned subsidiary of B.C. Hydro, the sole transmission provider in British Columbia.

   (b) Only entities within BC, such as Powerex and West Kootenay Power, can use British Columbia as a "source" and a "sink". All other potential importers to Alberta have to arrange for access through British Columbia. Point-to point services which, in effect, create an integrated service for access to Alberta from the U.S. border are potentially available. However, putting the path together is dependent on the other services that

may have already been sold on the interconnections. For example, if firm access to B.C. from the U.S. is available but all firm access from B.C. to Alberta has been sold by BC Hydro, then the integrated service is not directly available. Under these conditions a marketer must couple non-firm access on one tie together with firm access on the other tie to form a mixed wheel-through. This is a somewhat complicated process as the timing of sales for these services is not synchronized. This puts risk on a marketer who must buy one type of service at one point in time and then the other type of service later on. If he is successful in purchasing the first service but not the second he may end up with a transmission service that is not useful but which he is obliged to pay for. It is also noted that even if firm service was available on the B.C./Alberta side, there is a significant degree of risk with trying to couple this with non-firm service on the B.C./U.S tie as this service is susceptible to bumping through the "network economy" (network integration service) provisions of the BCH tariff – further discussion on the "network economy" issue follows.

Some have observed that the value of firm service to a network customer under the FERC wholesale tariff (such as Powerex) is arguably higher than to a customer who cannot use the jurisdiction as both a source and a sink. This is because the network customer can take advantage of the right of changing supply and delivery points under firm point to point service, given its ability to import into or export from B.C. For example, an importer who has non-firm rights into Alberta which are curtailed (and who has arranged firm capacity to wheel from the U.S. through B.C.), cannot salvage the firm U.S. leg of the wheel by using it to export from B.C. It cannot access B.C. supply to do so. Some perceive this as creating different economics for the two types of importers into Alberta.

(c) The priority of non-firm service, clearly secondary to firm, is further subject to invocation of network economy by BC Hydro's supply affiliate within B.C. The intended use of the right of network economy is to allow BC to access more economically resourced power from outside the province for use for native (network) load. The vagueness in the tariff as to what constitutes "economy energy purchases...from non-designed resources", and over what time frame that is calculated, makes it difficult for an importer to be assured that network economy will not be invoked during the term of its service contract.

Further, the other concerns which have been raised suggest issues around whether invocation of network economy has been consistent with the tariff. Simply stated, network economy has been invoked and exports from B.C. by Powerex have occurred concurrently. On the face of it, this is inconsistent with the basis for network economy—serving intra-BC needs.

Without a great deal of further investigation, the appropriateness of any given call on network economy cannot necessarily be established. (BC Hydro has adopted business practices clarifying that exports by Powerex during periods of network economy cannot occur without adequate point to point service being contracted by Powerex, but given the problems with access to data, auditing such matters would be difficult and resource intensive, to say the least).

(d) Access on the interconnections, particularly to space on the U.S./B.C interconnection, is complicated by problems with real time information lags and complexities around calculating available transmission capacity. These complexities are related to both physical limitations and operational factors (e.g. degree to which counterflows are taken into account in recognizing residual capacity). The MSA is not stating a position on how problematic these matters are in practice, but participants have indicated that predictability of space availability is not consistent.

Given the complexity of the issues and the lack of reach of the MSA into British Columbia, it is not possible or responsible to conclude that actions of BC Hydro have not been consistent with the WTS tariff and/or stated business practices, notwithstanding anecdotal evidence. It is noted that anecdotal information provided to the MSA suggests that use of network economy service coincident with Powerex exports to the U.S. or imports into Alberta is very frequent.

However, based on preliminary analysis, the MSA is concerned about the impacts on the PPoA market. For one period examined in detail—April 2000—Powerex was substantially in the lead on price setting at the higher price points. For example in April 2000, for the total time when the PPoA price was $100 or greater, Powerex was setting the price 51% of the time, and as noted above, for the time when PPoA price was $498 or greater, Powerex price setting accounted for 76%.

These high prices often occurred at times when there appeared to be unused available capacity on both B.C. interconnections (U.S. and Alberta), prices were lower in alternative markets and Powerex was the sole importer. (This is noted subject to the caveat that the complexities of BC Hydro's approach to calculating Available Transmission Capacity have not been factored in and a detailed audit as to other importers' availability of energy in such hours has not been done).

The key point is that in times of constrained supply within Alberta, importers can become the pivotal supplier. Further, if the competition on the tie is limited—due to the regulatory model for the BC WTS tariff, or otherwise—the PPoA market can arguably be disproportionately affected and/or reliability impacted by the actions of the successful importer. (See discussion below under Part C.1)

Again, whether or not there are tariff compliance issues or other concerns around competition law issues as to allocation or marketing of capacity on the BC interconnections, Alberta's "tools" in dealing with price impacts are limited. Two further points:

(i) The MSA has, for the past several months, stood down from commenting on these issues to allow the possibility of commercial solutions, and has participated in discussions between B.C. Hydro/Powerex, the TA and the PPoA on these issues. BC Hydro has offered limited concessions to the PPoA but not to the degree desired. The PPoA had proposed that an appropriately sized "corridor" through B.C. to Alberta be set aside that would not be subject to network economy invocation. This corridor would significantly enhance access to the Alberta market and would alleviate the structural problems associated with the B.C. Hydro wholesale tariff. It is recognized the changes which would assist Alberta's market are not in BC Hydro's or Powerex's

commercial interests, and as such the limited incentive and potential extent for any further "tuning" is understandable.

(ii) The MSA has conferred informally with the Competition Bureau and has requested that the Bureau consider whether the behaviour is of a type that could contravene the Competition Act.

As such, the MSA is recommending that the PPoA consider and develop some alternatives as to rules or rule changes which would insulate the Alberta market from the impact of imports under conditions which cannot be controlled within Alberta. Clearly, a great deal of due diligence is required to ensure that such a rule would conform with the principles of non-discrimination and other legal requirements, that it would be triggered only in appropriate or concerning circumstances (such as during times of export from B.C. coincident with invocation of network economy), and that it would have the appropriate mechanics (e.g. preclude import units from setting price, or cause override of offers by an appropriate reference price).

Also, since such a rule, however designed, would be interventionist this issue arguably goes beyond market design, and into market structure or principles of deregulation. It also carries with it the risk of further limitations on supply if it deters importers from participating. As such the ADRD needs to provide direction in this issue, which is of direct concern to the government as the architect of the deregulation model in Alberta.

If the decision taken is that the negatives of such a rule change—in effect "re-regulation"—outweigh the potential benefits or problems avoided, this needs to be communicated to the Alberta public.

One caveat is that no comment is made here on any possible structural disconnects on transmission from the Saskatchewan side. The analysis to date has focused on that part of the import sector— the west—that has been observed to be most pivotal in setting PPA price. For example, for January through June, SaskPower was much less influential than Powerex as a price setter for those periods when PPoA price was $100 or greater. More examination is worthwhile, however, given several months where SaskPower was the price setter in the range of 15% to 20% of the time that the PPoA price was $100 to $500. These occurred in months where Mid-Continent Area Power Pool ("MAPP") prices were significantly lower than markets to the west, suggesting that at least the obvious fundamentals may not provide a satisfactory explanation.

C. Behavioural Factors

1. Market Power and Exercise of Market Power

By far the most vexing problem for the MSA, the PPoA, the ADRD and stakeholders is the issue of market power, more specifically, the exercise of market power. At the very real risk of oversimplification, it has to be observed that the combination of the following suggests the possibility of the existence of market power, the opportunity to exercise it,

and the successful exercise of at least some market power in this jurisdiction, within the theoretical understanding of what constitutes exercise of market power:

(a) certain IPP supply blocks offered in at high prices, and at prices that appear to be in no way related to the level of production/operation costs or, given limitation on export access, to real opportunity costs. The result was price setting above $100 by these blocks for what appears to be a relatively high proportion of the time given the size of the resources. One IPP supplier has been responsible for setting prices above $500.

(b) large role of Powerex in price setting at high price levels, and often in the context of being the only importer;

(c) tight supply conditions during the summer maintenance months, making high priced resources the marginal blocks, with resultant system marginal price impacts.

(d) the electric industry in Alberta being characterized by highly inelastic demand, limited production capacity, and lack of storage, which impact on the existence and opportunity to exercise market power, as well as the returns to market power.

Due to the complexities of legitimate hydro bidding strategies, the high offer prices of hydro units experienced this summer cannot be suggested, even at a basic level, to be necessarily problematic on the basis of possible exercise of market power. Clearly, the contribution of hydro units to the recent high prices is greater than that of IPP's for a number of reasons, including size and quantity of resources provided by hydro, and the number of times hydro blocks were the marginal blocks on the system. Imports also have to be measured against opportunity costs, i.e. alternate markets prices during relevant times. As such, the magnitude of the concern around exercise of market power—even at a theoretical level—cannot be concluded at this time.

As important, there is as yet no existing practical definition of what constitutes exercise of market power within the PPoA. One of the textbook definitions of the existence of market power is the ability of a supplier to profitably influence the market price away from the price which would reflect a workably competitive market, by altering his supply decision. In a workably competitive market, all suppliers would be price takers. The exercise of market power is implementation, via offer strategy or behaviour, so as to influence price, rather than just acting as a price taker of the ultimate market clearing price. (A price taker offers quantities based on its marginal cost or opportunity cost; as a result of his quantities being dispatched, the market clearing price for an hour will be at or above his offer price/marginal cost, depending on whether higher cost units are needed in that hour to meet demand).

The most obvious way for a supplier to execute upon its market power is withholding of supply, either by economic withholding or physical withholding:

(a) Economic withholding—Again, in the simplest theoretical sense this involves offering production at greater than one's marginal or opportunity cost, with the result that the clearing price is higher than it otherwise would be.

(b) Physical withholding—This is constituted by holding back resources, with the intention and result of driving up market price. The impact of this is to require moving higher up the merit order to supply the last unit of demand than would otherwise be required, by removing a supply block—in the economist's frame of reference, this means shifting the supply curve to the left. (It is not readily apparent how this definition fits within the PPoA market in its present design, being a market with no capacity or commitment market. Physical withholding would appear to become relevant only to the extent that a supplier withdraws supply after its last opportunity to restate, and with the intention of influencing price [as opposed to a valid physical or operational reason such as force majeure or forced outage]).

Having said that, however, the MSA is concerned to understand the extent, if any, of unexplained irregularities in the availability of the regulated generating units. Given the current market structure, withholding of supply physically would exacerbate conditions which provide opportunities for other suppliers (or for the given supplier, on other assets) to experiment with strategies that may be in the category of economic withholding.

It should be readily apparent that there are a number of steps in the way prior to effective rule design or enforcement with respect to exercise of market power, not the least of which are:

(a) Definition and empirical proof of the level of system marginal price which would obtain, but for the exercise of market power. Key concerns include the need to have robust models and appropriate assumptions; among other things, this requires methodologies to factor in interactions between markets and the impact of imports, and a way to demonstrate the resultant price was a higher level than that required to attract imports;

(b) Identifying marginal cost or opportunity cost. In the case of imports, for example, this requires an understanding of market interactions, since the supply curve of the importer is not known (just the offer curve [quantities, not marginal/opportunity costs]);

(c) Policy decisions need to be made as to whether the intention is to attempt to design away and enforce all potential exercise of market power or to explicitly in the design allow for some potential level of exercise. Considerations behind this include different schools of thought on the need or value for the opportunity to exercise market power—some economists believe that a certain amount of potential recouping of returns to market power are necessary to attract investment (allow suppliers to recover fixed costs). As well, practically speaking, setting the operational rules at the theoretical standard—zero tolerance for exercise of market power—would be difficult to enforce given standards of proof and the difficulty in the quantitative analysis necessary in each case.

(d) The translation from a theoretical construct to a practical one involves such elements as magnitude, duration and the existence of a planned strategy. Overlays which find their way into practical definitions of market power or of the exercise of market include qualifiers such as "significance" of price impact, "sustainability" or "sustained effect" and the ability to "systematically" control or influence price. These approaches are found in anti-trust legal frameworks or under the FERC definition.

(e) To effectively design for compliance, whatever standards are chosen, the specifications have to be clear enough to meet several objectives—to signal expectations to Participants, and to enable proof of the non-compliance, when sanctions are necessary, and/or to be easy to administer. On the other hand, while proof requirements might be assisted by explicit standards, they also may allow potential for gaming or build in some level of inefficiencies. The other concerns with winding things too tightly are that only selective enforcement may be possible due to sheer volume and as a result adverse supplier behaviour will not be deterred. As well, arbitrary standards (especially with price mitigation approaches) may "regulate out" acceptable results along with truly anomalous results.

(f) The approach has to be capable of distinguishing between scarcity rents and market power (monopoly) rents. Proper market signals require the ability of suppliers to recoup true scarcity rents.

(g) Whatever is done has to be able to deal with hydro where cost based offering is not relevant.

As noted, the supply-demand situation in Alberta is tight and this is the source of the opportunity for even a small player to exercise market power—for example, notwithstanding a lack of material market share overall, such a supplier could have the "block of last resort" at the top end of the merit order in a given hour. In times where there is greater expectation that one's supply will be called on—i.e. less supply cushion—there is the opportunity to act strategically and less risk that that supply will be "priced out of the market" by supply from other (price-taking) producers. The impact on the market is twofold: (a) tight supply/greater demand means that higher cost units will be in merit since more of the available supply will be needed and higher priced blocks reached; (b) the prices in the merit order will be higher to the extent market power exercise is attempted.

As an alternative to dealing with the complications of codifying a definition for market power exercise and implementing rules consistent with the definition, a more simplistic (and easier to enforce) approach could be adopted, whether as an ongoing rule or triggered dependent on different market circumstances (such as during the continuation of expected supply demand tightness). For example, economic withholding could be deemed to occur by simply offering in over cost, assuming costs could be required to be reported and deemed as the supplier's offer ceiling. This would allow for mitigation and reset of the offer price or alternatively, be treated and enforced as any other rules non-compliance. Alternatively, an overall lower price cap or bid/offer caps could be adopted.

Concerns around any such approaches to market power exercise would include increased administrative burdens and the possible chilling effect on attracting new entrants or maintaining supply. (Other markets have been grappling with how to deal with market power longer than the PPoA and there have been no breakthroughs to speak of; blunt approaches may make the PPoA unique. The California ISO with its reduced $250 price cap is held up by some as an example of a market which has had the effect of driving away supply to markets not similarly constrained, and ironically forced the ISO into out-of-market purchases to replace the supply reductions, at offer prices above the cap. It also appears to have had the somewhat perverse effect of having players offer in more often close to the cap than they did with the higher cap levels—i.e. the cap is serving as a target rather than a ceiling.).

Similar to the suggestion of consideration of a rule to deal with interconnection and import problems, the approach to market power has to be made carefully. The major concern is that, however designed, rules to deal with this concern are to some extent backtracking from deregulation toward some form of price regulation or containment. This will mute market signals to bring in new investment and may delay or impede progress toward a workably competitive market. On the other hand, the circumstances or level of market maturity may be such that the essential elements for workable competition are not there—supply liquidity and demand response being key assumptions. In the current transitional period toward open competition, Alberta has all these problems. On that basis, some degree of market management might be preferred to unrestricted potential for the exercise of market power, given that it erodes the intended benefit of deregulation—reduced costs of energy to the consumer. The Catch 22 in all of this is that enforcement is either resource-intensive and therefore of limited reach, or to be effective has to operate through simplistic approaches that mitigate against letting competition operate and develop.

Once again, as with any approaches to interconnection access that the PPoA adopts, the direction and viewpoints of the ADRD on the general issue of market power exercise, and the desired approaches, need to be articulated. Dealing with the problem impacts directly on the deregulation or competitive model that the ADRD has implemented.

Markets in the United States which are attempting to build approaches to these concerns are struggling to find workable solutions under the oversight of the FERC. The question is how much mitigation or "regulation" would be useful to substitute for the market discipline which would exist in a market with true liquidity and adequate overall supply, and whether the benefits outweigh the negatives given the expected time over which Alberta will continue to suffer "growing pains". Clearly, the greater the opportunity and returns to the exercise of market power, the greater the argument for having a more prescriptive approach (i.e. bright line standards, easier standard of proof and defined price adjustments or penalties) so that enforcement effort is manageable and not "hit-and-miss". The disadvantages are equally clear - quasi-regulation and a blunt tool that will discipline away both competitive and non-competitive outcomes. In a mature market the oversight of market power exercises would be reduced to dealing with anomalies, rather than pervasive activities—an adequate supply and demand-side competition would provide the needed market discipline to make this possible.

Notably, neither here nor in the United States are concerns around exercise of market power—other than specific problems outlined in the Competition Act or U.S. anti-trust statutes such as predatory pricing, abuse of dominant position, and collusive activities around price influencing—dealt with explicitly under antitrust laws or other legislation. This understandably leaves a gap and suggests the need for debate around policy, jurisdiction, and legal issues. The MSA believes it would be useful for the ADRD to weigh in on these matters.

In terms of certain immediate considerations to deter some "speculative behaviour":

(1) One market design revision that the PPoA has been considering is a rule change to remove the ability of suppliers to be price-takers if they are out of merit. This flexibility arguably takes away the need for the supplier to make his offer price reflective of his true economics—he can make it on speculation that his energy might be called at that level if supply/demand conditions are tight enough. Otherwise if he has made the wrong guess and he risks not being dispatched, he can in effect enter the market and get dispatched at a lower price that is acceptable to him, but lower than his offer. As such, he has a risk-free bet.

(2) The PPoA should revive and reconsider its previous proposals around "orderly market rules". The essence of this is a "ticker" or defined increment for the five minute system marginal price to limit the price pressure, instead staging-up to the offer price level. This would mean that the unit which is dispatched would not have its offer immediately set the price and impact the price received for all generation. The trigger or conditions during which the ticker would apply would need to be defined.

(3) The issue of minimum block size eligible to set price is another area for priority review. This should also be helpful to "level the playing field" (smaller units have as many blocks to "draft up the merit order" as big units at present and relatively speaking, the offer flexibility for legitimate reasons, as well as experimentation, is greater for small units).

A last comment in this area is that the role of the Balancing Pool, during its tenure as a supply Participant, should be a positive factor. One of the tenets of the Market Achievement Plan is that the Balancing Pool's offer strategy will be such as not to adversely impact efficiency of the PPoA market. In terms of avoiding exercise of market power, or other potential manipulative actions, the Balancing Pool should be the model Participant.

2. Regulatory incentives

A brief comment will suffice here given that these influences will not operate past the end of the year.

The legislated hedges operate as a mitigation of market power. They also have the perverse effect of dulling the sensitivity of demand to the high costs of energy, at least to the degree that the utilities have not been short and thus applied for and received approval

to pass through increased power costs during this period of regulation. This may have the effect of delaying the move toward demand-side response and accordingly towards the required elements for competition; the full increase in the wholesale price is not sent through to the end-user.

IV Recommendations and Conclusions

Based on the foregoing concerns that have been observed in the PPoA market, the MSA has identified the following action items or priority areas:

A. The MSA is going to undertake a review of outages, derates and maintenance of regulated units during spring and summer of 2000. First steps have been taken toward retaining consultants. Results of this study will be shared between the PPoA, AEUB and the Transmission Administrator (the regulated units are committed sources of system support services for the TA, with contractual restrictions on unavailability and compensation for those services based on opportunity costs [PPoA price of energy]).

B. The MSA will design and implement a process around ongoing collection of information and reporting from generators on planned maintenance and forced outages, in the context of developing review criteria for the review of compliance with the of availability provisions under the PPA's. In conjunction with this the MSA will approach owners and buyers of the PPA's regarding their progress to date in operationalizing the Protocol on information exchange principles documented prior to the PPA auction. The approaches around availability reporting will also be coordinated with the MSA's and the PPoA's ongoing review of provision of information to Participants.

C. It is recommended that the PPoA, in the very near term, develop and implement appropriate rule changes to deal with the impact of interconnection concerns as discussed above in Section B. 4.

D. The experience of summer 2000 prices reinforces the need for continuous review and evaluation of the PPoA market design In particular, the PPoA should continue to review rules around restatements of quantities offered into the market, or intra-day market structures to deal with disconnects between the PPoA and other markets, and in order to ensure the appropriate balance between flexibility offered to suppliers and the need for meaningful price transparency. The PPoA, with the MSA's input, should also continuously review and evaluate the timing and content of market information provided to Participants. Lastly the unique factors affecting hydro need to be considered with respect to whatever changes are made, and also with regard to the current restatement rules and other "mechanical" rules.

In particular, as a medium term priority over and above the rules changes being considered now (noted in C.), the MSA suggests that the PPoA undertake a review of the price cap level, as well as price cap setting methodologies and approaches that would be appropriate (including offer or revenue caps, or adjustable caps).

E. The MSA is committing resources toward an improved program of monitoring approaches and tools in the PPoA, as well towards development of standards and guideposts for reviewable behaviour and compliance/enforcement approaches.

F. Demand side participation is arguably as important to the existence of a true competitive market as liquidity on the supply side. Clearly, given that retail competition is the last stage of the deregulation process, it is at an earlier stage of evolution than generation deregulation which started with opening up market entry and is now complete with the auction of the PPA's. The retail side, in contrast, is going to be opened up on January 1, 2001 but has a built-in "governor" on the pace of competition given the regulated rate option. This option is available to a large percentage of the total load in the province. This is certainly understandable given the need to grade into full competitive rates, but it is just raised as a comment that progress on this side will take some time.

It is essential that stakeholders—especially those on the load side—take an active role, rather than just leaving it to retailers and prospective retailers to set the direction for price responsiveness, types of offerings and valuation methods for interruptibility. Involvement of industry organizations such as IPCCAA, as well as industrial customers (individually, through joint ventures or through aggregators) are key to progress in this area.

Discussion of considerations here is beyond the scope of this paper, but it suffices to say that the burden of developing demand response does not fall squarely on any one entity. The PPoA and forwards market operators, the government and regulators need to ensure that the framework for participation is in place and is reasonably designed, but only Participants—retailers and others—can bring the price signals to the market. PPoA and government programs (such as Voluntary Load Curtailment Program or metering infrastructure subsidies), may have their place in the transition as incentives to demand, but should not be a substitute for initiatives or active participation from the market players. Likewise, the market design can be tuned to give a nudge to participation—e.g. required price bidding by load participants of certain size, rather than allowing price-taking—but as with the supply side, "over-engineering" the rules can cause its own distortions or amount to re-regulation.

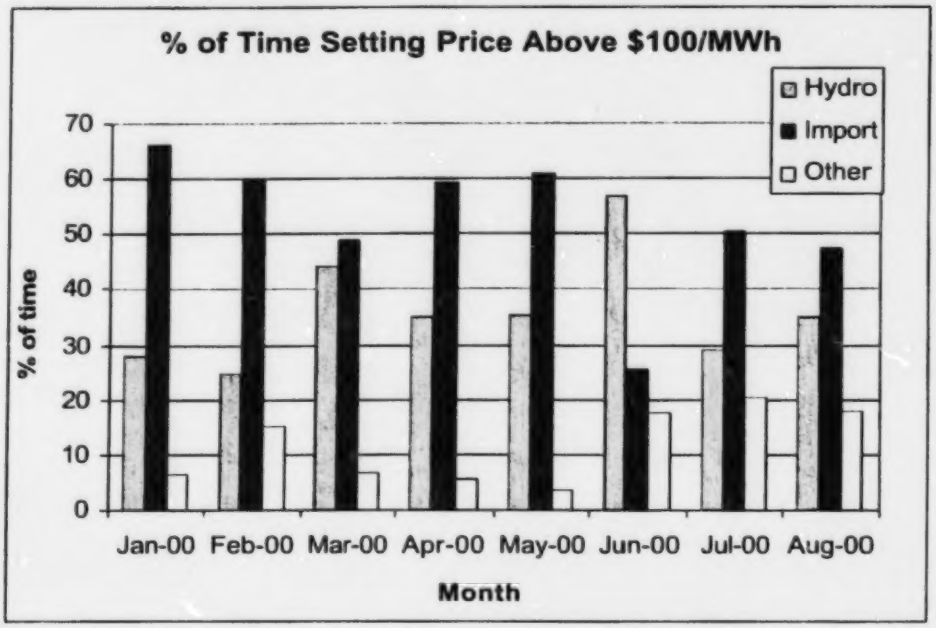
G. The MSA supports any initiatives by the ADRD towards removing legislative barriers to developments in the overall electricity market structure, such as opening up direct sales eligibility requirements. The ADRD may also wish to consider any structural changes which would be appropriate, such as a capacity market, and the relationship of that within the energy and ancillary services markets framework.

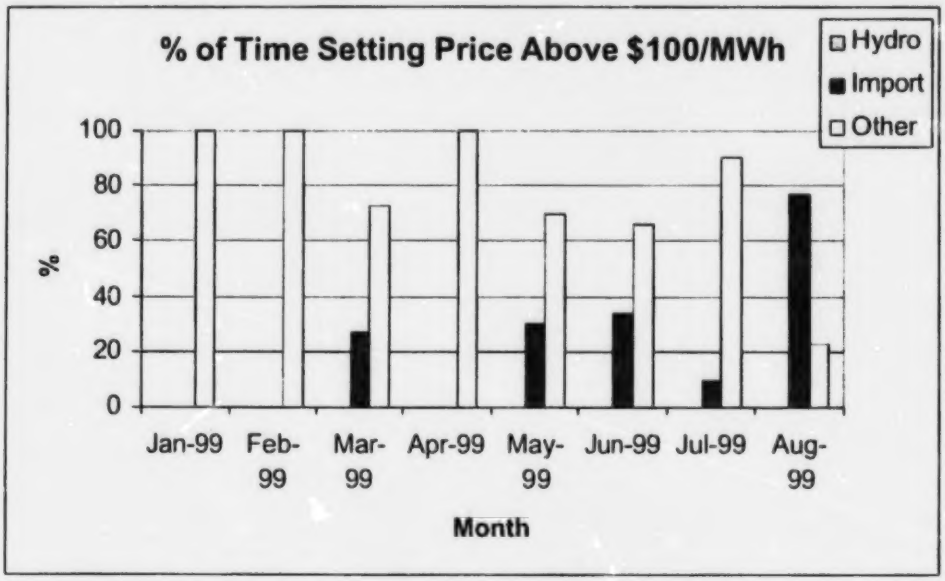
H. The TA should explore additional opportunities or arrangements for providing operating reserves that bring in new sources of supply beyond those presently available—such as exchange or import arrangements with other jurisdictions, further offerings for curtailable load, and the like, whether these are achieved through the ancillary services market or otherwise.

I. It is noted that Alberta's place in a Regional Transmission Organization ("RTO") is a pivotal strategic issue (refer to Power Pool fact file - Regional Transmission Organizations). As well, the groundwork should be started now to facilitate the appropriate level and siting of

new interconnection(s). This needs to be considered to gauge what additional access is needed to truly open up the Alberta market, in order to meet demand and to encourage generation development within Alberta.

ATTACHMENT A





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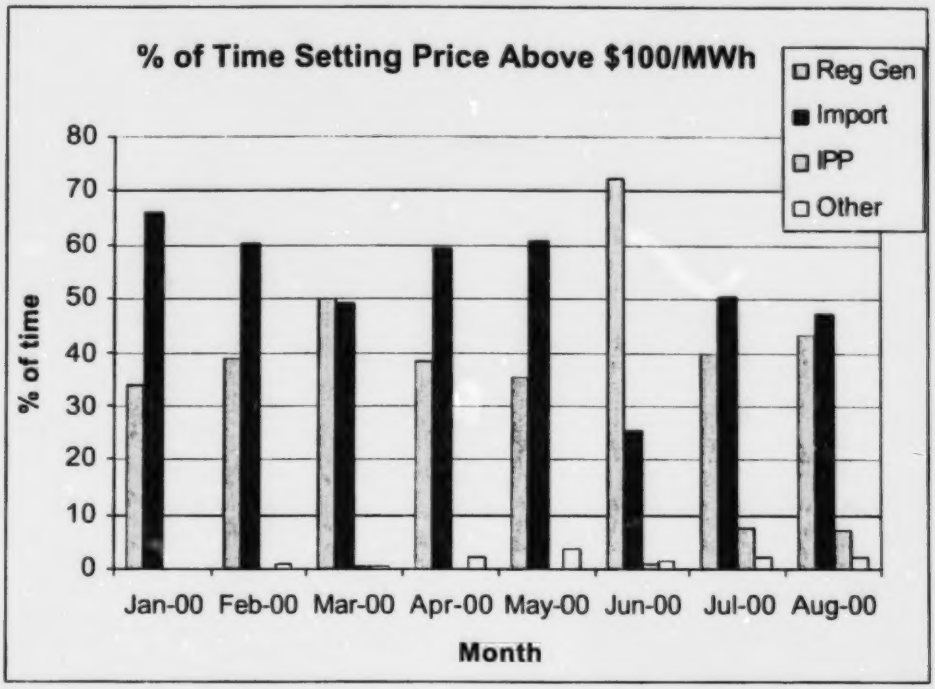

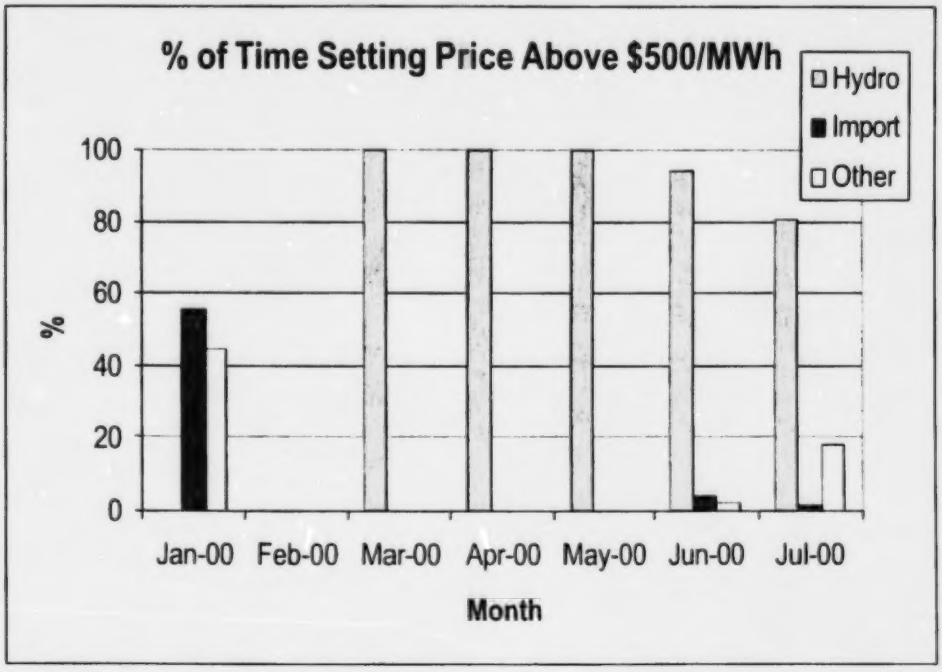

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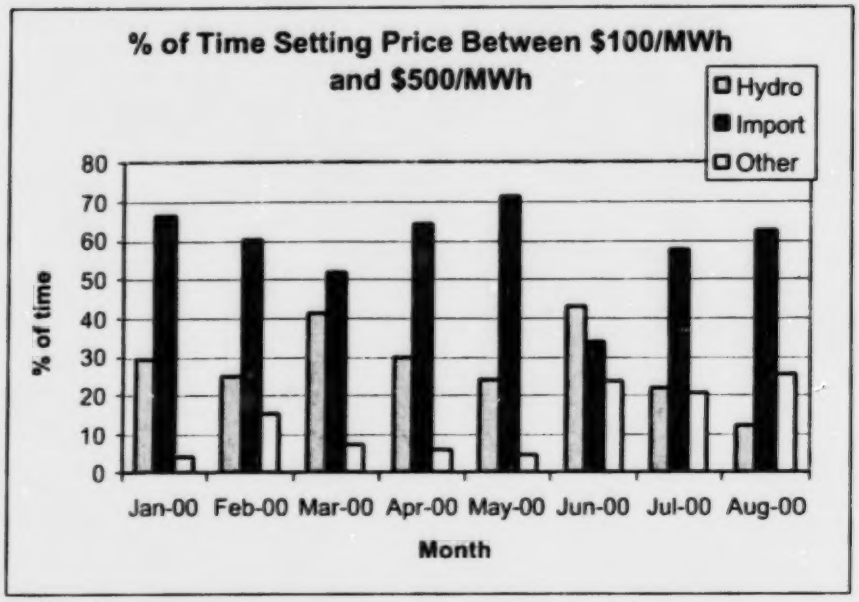
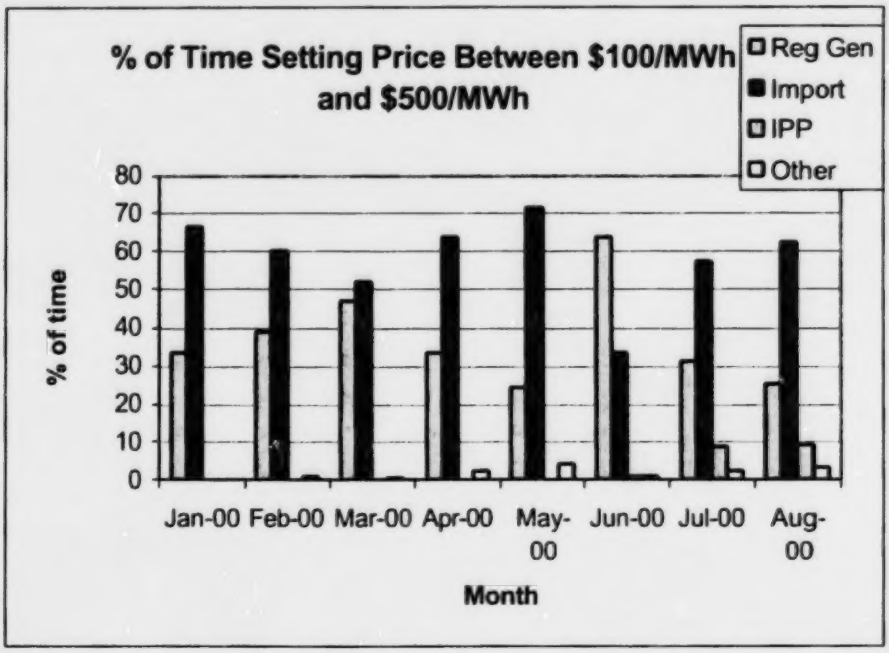




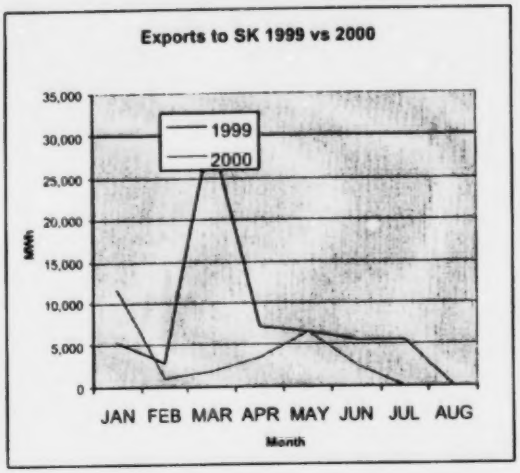
ATTACHMENT B

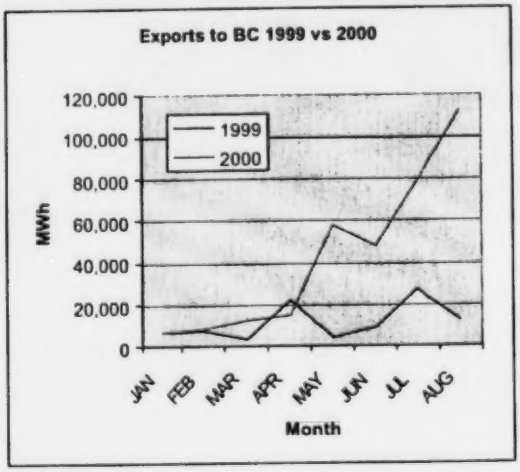
	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99
PRICE								
Maximum	97.50	85.87	367	694.16	740.74	998	806.42	998
Minimum	11.99	11.99	11.99	11.99	11.99	5.79	5.76	5.80
Average	32.06	28.27	29.21	31.41	51.15	54.63	31.17	66.46
DEMAND								
Maximum	7127	6854	6674	6409	6336	6567	6752	6812
Minimum	5146	5155	4967	4763	4652	4653	4815	4727
Average	6128	5980	5866	5654	5549	5651	5755	5822

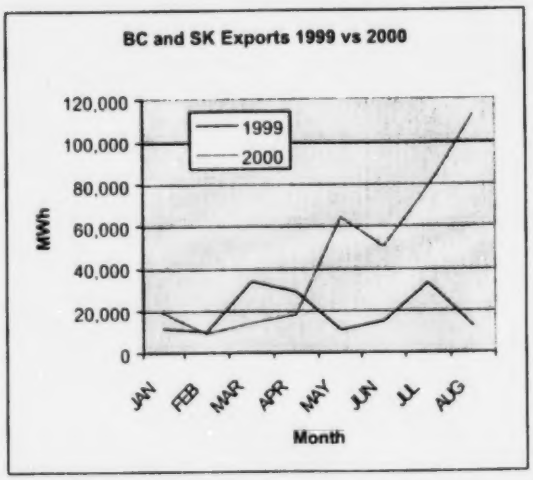
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00
PRICE								
Maximum	747.00	499.98	551.23	544.61	501.47	995	755.32	994
Minimum	5.84	18.50	12.56	6.44	9.13	12.55	24.90	18.07
Average	46.46	47.07	77.19	93.68	51.66	106.73	124.11	202.09
DEMAND								
Maximum	7357	7182	6946	6609	6675	7009	7150	6997
Minimum	5269	5337	5189	5091	5088	4999	5091	5212
Average	6353	6259	6085	5887	5900	5994	6151	6108

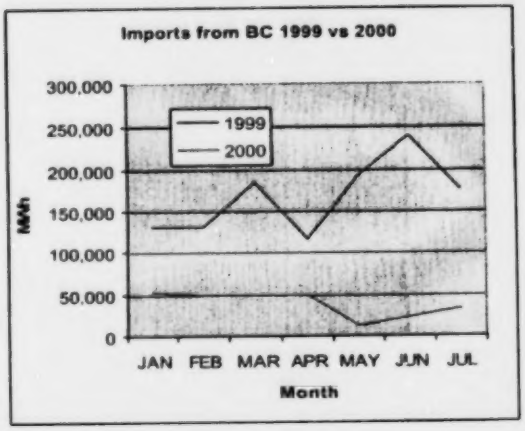
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
% Change Avg Price	44.92	66.52	164.31	198.27	1.00	95.38	298.15	204.06
% Change Avg Demand	3.67	4.67	3.72	4.12	6.33	6.07	6.88	4.91

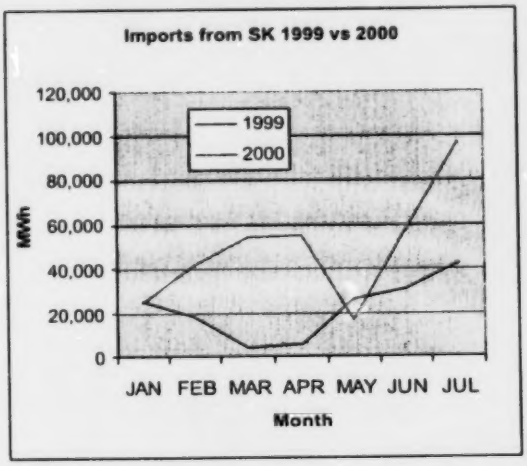
ATTACHMENT C

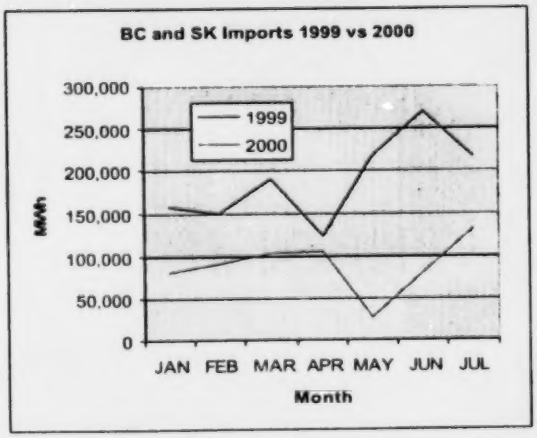







Imports from BC 1999 vs 2000
300,000
250,000
200,000
150,000
100,000
50,000
0
MWh
1999
2000
JAN FEB MAR APR MAY JUN JUL
Month


Imports from SK 1999 vs 2000
120,000
100,000
80,000
60,000
40,000
20,000
0
MWh
1999
2000
JAN FEB MAR APR MAY JUN JUL
Month


BC and SK Imports 1999 vs 2000
300,000
250,000
200,000
150,000
100,000
50,000
0
MWh
1999
2000
JAN FEB MAR APR MAY JUN JUL
Month